FOSTER WHEELER ENVIRONMENTAL CORPORATION

Mr. Steve Larson
Executive Director
California Energy Commission
1516 Ninth St.
MS-4
Sacramento, CA. 95814

February 21, 2002

Attention: Dockets Unit

Re: Inland Empire Energy Center Project- Docket No. 01-AFC-017
Data Responses to CEC Staff Data Requests dated January 14, 2002

Dear Mr. Larson:

Enclosed are twenty-six (26) sets of the Data Responses for the Inland Empire Energy Center Project (original signed document and 25 copies). This data is submitted in response to the staff's Data Requests dated January 14, 2002. The enclosed data consists of revised responses and responses to data requests for which the Inland Empire Energy Center project requested additional time per the "Notification of Need for Additional Time to Prepare Responses and Objection to California Energy Commission Staff Data Requests" dated January 24, 2002.

Additionally, the CD's containing the air modeling files (7 copies) as requested by staff are included as part of this filing.

Dated this 21st day of February, 2002.

Sincerely,

RB Booth

Richard B. Booth
Project Manager

Attachments

ISO 14001

1940 E. Deere Avenue, Suite 200, Santa Ana, CA 92705
Tel: 949-756-7500 Fax: 949-756-7560

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

	)	Docket No. 01-AFC-17
APPLICATION FOR CERTIFICATION	)	
FOR THE INLAND EMPIRE ENERGY	)	PROOF OF SERVICE
CENTER	)	(Revised 02/01/02)
______________________________	)	

I, __Richard B. Booth__, declare that on __Februrary 21, 2002__, I served copies of the attached __Responses to California Energy Commission Staff's Data Requests 1-161__ by Federal Express, for delivery to Sacramento, by depositing such envelope in a facility regularly maintained by Federal Express with delivery fees fully provided for or delivered the envelope to a courier or driver of Federal Express authorized to receive documents at Foster Wheeler Environmental Corp., 1940 East Deere Ave., Suite 200, Santa Ana, CA 92705 with delivery fees fully provided, for delivery to the following:

DOCKET UNIT

Original signed document plus 25 copies.

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 01-AFC-17
DOCKET UNIT, MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

In addition to the documents sent to
the Commission Docket Unit:

I, **Richard B. Booth** , declare that on **Februrary 21, 2002** , I deposited copies of the attached **Responses to California Energy Commission Staff's Data Requests 1-161** in the United States mail at Santa Ana, CA with first class postage thereon fully prepaid and addressed to the following:

APPLICANT

Gregory A. Lamberg
Calpine Corporation
4160 Dublin Blvd.
Dublin, CA 94568-3139
gregl@calpine.com

Michael Hatfield
Calpine Corporation
4160 Dublin Blvd.
Dublin, CA 94568-3139

Jenifer Morris
NJ Resources, LLC
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Long Beach, CA 90802

COUNSEL FOR APPLICANT:

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Ann Trowbridge
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INTERVENORS

CURE
C/O Marc D. Joseph, Esq.
Mark R. Wolfe, Esq.
Adams Broadwell Joseph & Cardozo
651 Gateway Blvd., Suite 900
South San Francisco, California 94080

Romoland School District
C/O Mark Luesebrink, Esq.
Jeffrey M. Oderman, Esq.
Rutan & Tucker , Attorneys at Law
611 Anton Blvd., 1th Fl.

Costa Mesa, CA 92626
mluesebrink@rutan.com

INTERESTED AGENCIES

Eastern Municipal Water District
Attn: Dick Heil
2270 Trumble Road
P.O. Box 8300
Perris, CA 92572-8300
heild@emwd.org

Independent System Operator
Jeffery Miller
151 Blue Ravine Road
Folsom, CA 95630
jmiller@caiso.com

Electricity Oversight Board
Gary Heath, Executive Director
770 L Street, Suite 1250
Sacramento, CA 95814

Paul Clanon, Director
Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

I declare under penalty of perjury that the foregoing is true and correct.

Richard B Booth

Richard B. Booth

* * * *

DATA RESPONSES 1 THROUGH 161

FOR

INLAND EMPIRE ENERGY CENTER

SUBMITTAL 2

Compiled by

FOSTER WHEELER ENVIRONMENTAL CORPORATION
1940 E. Deere Avenue, Suite 200
Santa Ana, CA 92705

February 20, 2002

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AIR QUALITY RESPONSES

Request 2 – The short-term NO_x emissions from the peak month of activity of construction equipment were modeled (AFC Appendix K-2) to determine compliance with the NO_2 standard. This equipment is capable of generating about 130 lb/day of NO_x (AFC Appendix K-2, Table K.2-2). Preliminary review of the modeling files submitted electronically indicates that the area source of NO_x emissions was modeled at an hourly average emission rate of 1.712×10^{-5} grams per second per square meter. Please provide supporting calculations explaining how the modeled short-term NO_x emission rate (in terms of g/s-m^2) is derived from the daily emission rate of approximately 130 lb/day, and reevaluate ambient impacts with use of the ozone limiting method (OLM), if necessary.

> **Response 2** – Text response was provided in the Data Responses submitted to the CEC on February 13, 2002. Electronic copies of the requested modeling files for Data Requests 2, 3, 17, and 24 are included on the enclosed CD's (7 copies).

Request 3 – Preliminary review of the modeling files submitted electronically indicates that the construction considers area sources are modeled with emissions occurring only between the hours of 8 a.m. and 4 p.m. These hours are inconsistent with the 7 a.m. to 7 p.m. construction schedule anticipated for the project (AFC p. 3-50). Please describe the basis for modeling source operation for an eight-hour duration when a 12-hour duration is anticipated to be necessary, and reevaluate ambient impacts based on the 12-hour daily schedule, if necessary.

> **Response 3** – Text response was provided in the Data Responses submitted to the CEC on February 13, 2002. Electronic copies of the requested modeling files for Data Requests 2, 3, 17, and 24 are included on the enclosed CD's (7 copies).

Request 17 – Please demonstrate why the two scenarios in the AFC would conservatively characterize commissioning conditions by summarizing the emissions and stack parameters assumed for other commissioning tasks.

> **Response 17** – Text response was provided in the Data Responses submitted to the CEC on February 13, 2002. Electronic copies of the requested modeling files for Data Requests 2, 3, 17, and 24 are included on the enclosed CD's (7 copies).

Request 24 – Text response was provided in the Data Responses submitted to the CEC on February 13, 2002. Please acknowledge the modeled exceedance of the annual NO_2 PSD Significance Level identified in AFC Table 5.2-26 p. 5.2-43 and electronic modeling files, or provide additional analysis, if necessary, to demonstrate that the PSD Significance Level would not be exceeded.

> **Response 24** – Electronic copies of the requested modeling files for Data Requests 2, 3, 17, and 24 are included on the enclosed CD's (7 copies).

Request 31. Please identify any and all emission sources that would be associated with construction of the compressor station.

> **Response 31** –Applicant will provide this data on March 13, 2002.

BIOLOGICAL RESOURCES RESPONSES

Request 40 – Provide a matrix of projects considered in the cumulative air quality analysis proposed in Section 5.2.5 of the AFC. In your results, indicate the amount of nitrogen deposition from the cumulative projects using the values tons per year and kg/ha-yr. The matrix should include the source's distance and direction from the proposed power plant, the amount of NO_x emitted using the values tons per year and kg/ha/yr, and a short description (or assumptions made) of the sources. Once all projects have been identified, using the ISCST3 model, provide the cumulative nitrogen deposition on the Class I wilderness areas identified in Table 5.3-11 of the AFC. Provide an isopleth graphic over a USGS 7.5 minute quadrangle maps (or equally detailed map or more current map) of the direct deposition values (not weighted average). Please note that Data Request #40 addresses this issue as well.

Response 40 – See Data Response 40 in applicant's February 13, 2002 submittal. Table 40-1 summarizes the maximum modeled cumulative nitrogen deposition impacts on the nearby Class I areas. Enclosed, as Bio Attachment 3 is a figure showing the isopleths for the cumulative nitrogen deposition modeling analysis. Copies of the cumulative nitrogen deposition modeling files will be submitted to the CEC as a separate submittal.

Table 40-1
Maximum Modeled Cumulative Nitrogen Deposition Impacts on Class I Areas (IEEC Project)

Pollutant	Maximum Cumulative Impact (Kg/ha-yr)	
Total Nitrogen Deposition	San Gabriel	0.00004
	Cucamonga	0.00057
	San Gorgonio	0.00229
	San Jacinto	0.01328
	Agua Tibia	0.03730
	Joshua Tree	0.00864

Note:
Kg/ha-yr = kilograms per hectare per year

Request 42 – Please provide a detailed outline of the "Biological Resources Mitigation Implementation and Monitoring Plan" (BRMIMP) which includes the applicant's biological resources mitigation measures and the HCP's incidental take measures for Stephen's kangaroo rat (Riverside County Habitat Conservation Agency 1996).

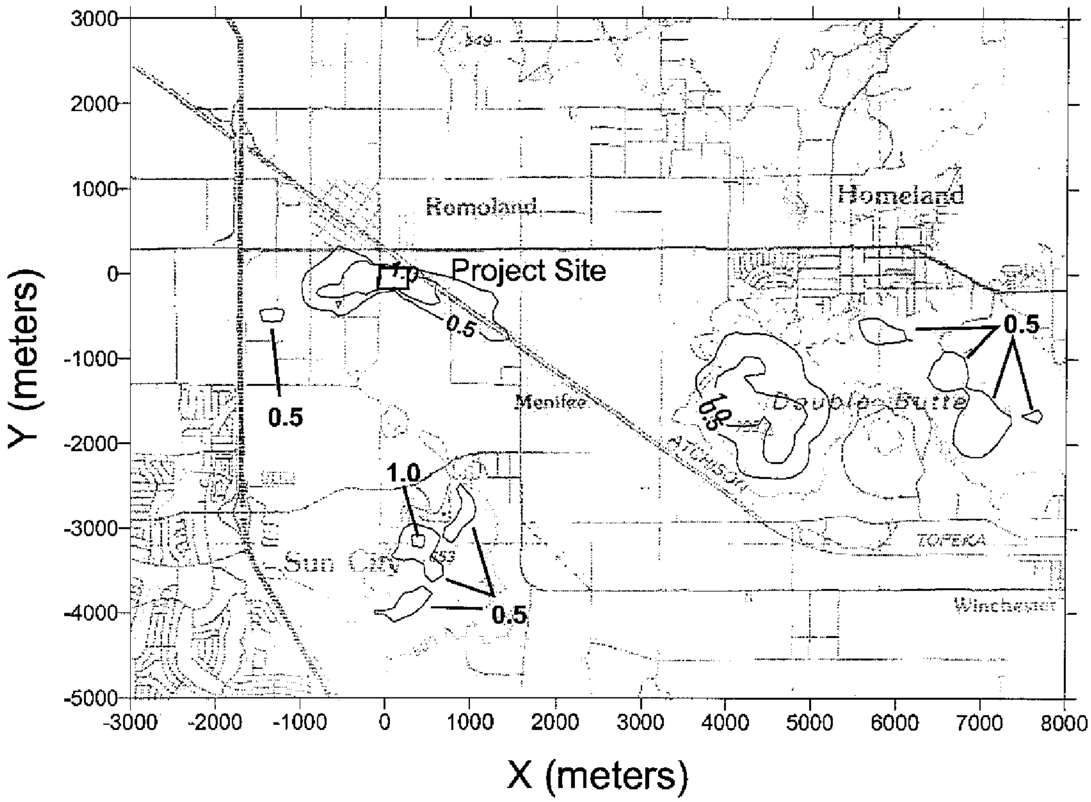
Response 42 – See Applicant's Data Response submittal dated February 13, 2002.

Bio Attachment 4 contains copies of the Riverside County SKR Habitat Conservation Plan "incidental take" measures.

BIO ATTACHMENT 3

CUMULATIVE NITROGEN DEPOSITION ISOPLETHS

Cumulative Nitrogen Deposition - kg N/(ha-yr)



BIO ATTACHMENT 4

SKR "TAKE PERMIT" PROVISIONS

Terms and Conditions in the Short-Term HCP Regarding Incidental Take of SKR

The original terms and conditions imposed on incidental take of SKR under the RCHCA's existing 10(a) permit and 2081 agreement are described below:

1. Within the HCP area incidental take of SKR can occur only on land located outside of the boundaries of Study Areas. Incidental take within Study Areas was authorized only for essential public utility projects, and only with the specific approval of USFWS and CDFG;

2. Incidental take could not exceed 4,400 acres or 20% (whichever is less) of the total amount of occupied SKR habitat in the HCP area;

3. For every one acre of incidental take occurring outside of Study Areas, one acre of SKR occupied habitat located within the Study Areas must be acquired by the RCHCA, placed in public ownership, and permanently conserved for the benefit of the species. All RCHCA replacement land acquisitions must be approved by USFWS and CDFG;

4. RCHCA replacement acquisition acreage must be no less than 10% below actual incidental take acreage, as measured every six months;

5. When reviewing projects proposed within a Study Area, RCHCA members must:

    a. Require that a SKR biological report on the project be prepared by a biologist permitted by USFWS to trap the species;

    b. Consider the effects of the project on reserve design and require preparation of an EIR if the potential effects are significant;

    c. Provide USFWS and CDFG with an early opportunity to comment, and;

    d. For the project to be approved, make a finding of "no significant environmental effect" on the future establishment of a SKR reserve in the Study Area.

6. RCHCA members were required to collect a SKR mitigation fee as a condition precedent to issuance of grading, building, surface mining, and other land disturbance and permits in the HCP area. Mitigation fee revenues were expended by the RCHCA for implementation of the Short-Term HCP, including habitat acquisition, biological research, and preserve system planning. A minimum of 10% of SKR mitigation fees must be dedicated to habitat management;

7. Boundaries of the HCP area and Study Areas could be modified only with the approval of USFWS and CDFG. The RCHCA could petition for such changes once every six months, with all proposed changes accompanied by SKR biological surveys and appropriate CEQA and NEPA environmental documentation, and;

8. The authorization for incidental take of SKR was valid for an initial period of two years.

In response to formal requests from the RCHCA, USFWS and CDFG approved the following amendments to the permit and agreement:

1. The habitat replacement requirement was modified to allow for mitigation credit to be given by USFWS and CDFG on a case-by-case basis for the acquisition of non-SKR occupied habitat deemed important to preserves as buffers or corridors;

2. The term of the existing permit and agreement was extended until June 30, 1996;

3. A provision was added to allow authorized incidental take to occur any time within 15 years of the expiration of the permit and agreement, provided that the applicable SKR mitigation fees have been paid, replacement habitat has been acquired, and all other terms and conditions of the permit and agreement have been met;

4. Projects involving essential public utilities within Study Areas were more specifically defined as those for "...water, electricity, gas, and the like, in which no reasonable alternative location or route is available, taking into account comparable environmental consequences and costs of installation, and subject to approval of appropriate mitigation" by USFWS and CDFG.

GEOLOGY AND PALEONTOLOGY RESPONSES

Request 51 – Please provide references to the information on flood potential, including the appropriate FEMA map(s).

Response 51 – The FEMA conditional approval letters identifying the most recent changes to the flood insurance rate maps (Figures 51-1 and 51-2, DR submittal dated 2-13-02) are enclosed in Geology/Paleo Attachment 1. Also included in Attachment 1 is the revised flood insurance rate map showing the changes as delineated in the FEMA approval letters.

GEOLOGY & PALEONTOLOGY ATTACHMENT 1

16-011

Federal Emergency Management Agency

Washington, D.C. 20472

FEB 20 2001

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

IN REPLY REFER TO:
Case No.: 00-09-706R

The Honorable Tom Mullen
Chairman, Riverside County Board of Supervisors
County Administrative Center
4080 Lemon Street, Fourth Floor
Riverside, CA 92501

Community: Riverside County, CA
Community No.: 060245

104

Dear Mr. Mullen:

This responds to a request that the Federal Emergency Management Agency (FEMA) comment on the effects that a proposed project would have on the effective Flood Insurance Rate Map (FIRM) and Flood Insurance Study (FIS) report for your community in accordance with Part 65 of the National Flood Insurance Program (NFIP) regulations. In a letter dated May 10, 2000, Mr. Scott R. Hildebrandt, P.E., Principal Engineer, Albert A. Webb Associates, requested that FEMA evaluate the effects that updated topographic and hydrologic data along Ethanac Wash from its confluence with the San Jacinto River to just downstream of the Atchison, Topeka & Santa Fe Railway (project reach); an existing bridge at Interstate Highway 395 (I-395); and proposed placement of fill for the development of Tract 29113 along Ethanac Wash from approximately 1,500 feet upstream to approximately 2,600 feet upstream of I-395 would have on the flood hazard information shown on the effective FIRM and FIS report.

All data required to complete our review of this request for a Conditional Letter of Map Revision (CLOMR) were submitted with letters from Mr. Hildebrandt.

We reviewed the submitted data and the data used to prepare the effective FIRM for your community and determined that the proposed project meets the minimum floodplain management criteria of the NFIP. The submitted existing conditions HEC-2 hydraulic computer model, dated November 21, 2000, based on updated topographic and hydrologic information, was used as the base conditions model in our review of the proposed conditions model for this CLOMR request. We believe that, if the proposed project is constructed as shown on the plans entitled "Tract No. 29113 Rough Grading Plan," Sheets 1 through 4, prepared by Lohr & Associates Inc., dated October 19, 1999, and the data listed below are received, a revision to the FIRM would be warranted.

Our review of the existing conditions analysis revealed that the width of the Special Flood Hazard Area (SFHA), the area that would be inundated by the flood having a 1-percent chance of being equaled or exceeded in any given year (base flood), increased in some areas and decreased in other areas compared to the effective SFHA width along the project reach of Ethanac Wash. The maximum increase in SFHA width, approximately 700 feet, occurred approximately 2,200 feet downstream of I-395. The maximum decrease in SFHA width, approximately 1,300 feet, occurred approximately 3,200 feet upstream of I-395.

The proposed project will not affect the existing conditions Base Flood Elevations (BFEs), SFHA width, or regulatory floodway width.

In addition to the changes described above, the zone designation along Ethanac Wash will change from Zone A, an SFHA with no BFEs determined, to Zone AE, an SFHA with BFEs determined, and a regulatory floodway will be added to the FIRM.

Upon completion of the project, your community may submit the data listed below and request that we make a final determination on revising the effective FIRM and FIS report.

- Our review of the submitted data revealed that the embankment of Ethanac Road east of its intersection with I-395 is acting as a levee. Documentation to show that the embankment meets the requirements of Section 65.10 of the NFIP regulations must be submitted before we can make a final determination on revising the FIRM. If the embankment cannot meet these requirements, then a new hydraulic analysis assuming the levee does not exist must be submitted, and the SFHA must be mapped in accordance with the procedures outlined in the publication *Guidelines and Specifications for Study Contractors* (FEMA 37).

- Our review of the submitted data revealed several discrepancies between the calculated floodway topwidths in the existing conditions and proposed conditions HEC-2 models and those shown on the submitted work map. Although these discrepancies did not affect our evaluation of the impact of the Tract 29113 development on the existing conditions flood hazards, they must be resolved before we can revise the effective FIRM.

- Detailed application and certification forms, which were used in processing this request, must be used for requesting final revisions to the maps. Therefore, when the map revision request for the area covered by this letter is submitted, Form 1, entitled "Revision Requester and Community Official Form," must be included. (A copy of this form is enclosed.)

- The detailed application and certification forms listed below may be required if as-built conditions differ from the preliminary plans. If required, please submit new forms (copies of which are enclosed) or annotated copies of the previously submitted forms showing the revised information.

  Form 3, entitled "Hydrologic Analysis Form"

  Form 4, entitled "Riverine Hydraulic Analysis Form"

  Form 5, entitled "Riverine/Coastal Mapping Form"

  Form 7, entitled "Bridge/Culvert Form"

  Form 8, entitled "Levee/Floodwall System Form"

  Hydraulic analyses, for as-built conditions, of the base flood and the regulatory floodway must be submitted with Form 4, and a topographic work map showing the revised floodplain and floodway boundaries must be submitted with Form 5.

- Effective June 1, 2000, FEMA revised the fee schedule for reviewing and processing requests for conditional and final modifications to published flood information and maps. In accordance with this schedule, the current fee for this map revision request is $3,400 and must be received before we can begin processing the request. Please note, however, that the fee schedule is subject to change, and requesters are required to submit the fee in effect at the time of the submittal. Payment of this fee shall be made in the form of a check or money order, made payable in U.S. funds to the National Flood Insurance Program, or by credit card. The payment must be forwarded to the following address:

  Federal Emergency Management Agency
  Fee-Charge System Administrator
  P.O. Box 3173
  Merrifield, VA 22116-3173

- As-built plans, certified by a registered professional engineer, of all proposed project elements

- Community acknowledgment of the map revision request

- Certification that all fill placed in the currently effective base floodplain and below the proposed BFE is compacted to 95 percent of the maximum density obtainable with the Standard Proctor Test method issued by the American Society for Testing and Materials (ASTM Standard D-698) or an acceptable equivalent method for all areas to be removed from the base floodplain

- A letter stating that your community will adopt and enforce the modified regulatory floodway, OR, if the State has jurisdiction over either the regulatory floodway or its adoption by your community, a copy of your community's letter to the appropriate State agency notifying it of the modification to the regulatory floodway and a copy of the letter from that agency stating its approval of the modification

- An officially adopted maintenance and operation plan for the Ethanac Road embankment. This plan, which may be in the form of a written statement from the community Chief Executive Officer, an ordinance, or other legislation, must describe the nature of the maintenance activities, the frequency with which they will be performed, and the title of the local community official who will be responsible for ensuring that the maintenance activities are accomplished.

- Documentation that all fill exposed to floodwater during the base flood is protected from the forces of erosion as specified in Paragraphs 65.5(a)(6)(iii) and (iv) of the NFIP regulations

After receiving appropriate documentation to show that the project has been completed, FEMA will initiate a revision to the FIRM and FIS report. Because BFEs would be added to the FIRM, a 90-day appeal period would be initiated, during which community officials and interested persons may appeal the revised BFEs based on scientific or technical data.

This CLOMR is based on minimum floodplain management criteria established under the NFIP. Your community is responsible for approving all floodplain development and for ensuring all necessary permits required by Federal or State law have been received. State, county, and community officials, based on knowledge of local conditions and in the interest of safety, may set higher standards for construction in the SFHA. If the State, county, or community has adopted more restrictive or comprehensive floodplain management criteria, these criteria take precedence over the minimum NFIP criteria.

If you have any questions regarding floodplain management regulations for your community or the NFIP in general, please contact the Consultation Coordination Officer (CCO) for your community. Information on the CCO for your community may be obtained by calling the Chief, Community Mitigation Programs Branch, Mitigation Division of FEMA in San Francisco, California, at (415) 923-7184. If you have any questions regarding this CLOMR, please call our Map Assistance Center, toll free, at 1-877-FEMA MAP (1-877-336-2627).

Sincerely,

Max H. Yuan, P.E., Project Engineer
Hazards Study Branch
Mitigation Directorate

For: Matthew B. Miller, P.E., Chief
Hazards Study Branch
Mitigation Directorate

Enclosures

cc: The Honorable Daryl Dusch
Mayor, City of Perris

Mr. Habib Motlagh
City Engineer
City of Perris

Mr. Howard L. Dickerson
Senior Civil Engineer
Flood Control and Water Conservation District
Riverside County

Mr. Scott R. Hildebrandt, P.E.
Principal Engineer
Albert A. Webb Associates

Federal Emergency Management Agency

Washington, D.C. 20472

FEB 2 0 2001

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

IN REPLY REFER TO:
Case No.: 00-09-706R

The Honorable Daryl Dusch
Mayor, City of Perris
101 North D Street
Perris, CA 92570

Community: City of Perris, CA
Community No.: 060258

104

Dear Mayor Dusch:

This responds to a request that the Federal Emergency Management Agency (FEMA) comment on the effects that a proposed project would have on the effective Flood Insurance Rate Map (FIRM) and Flood Insurance Study (FIS) report for your community in accordance with Part 65 of the National Flood Insurance Program (NFIP) regulations. In a letter dated May 10, 2000, Mr. Scott R. Hildebrandt, P.E., Principal Engineer, Albert A. Webb Associates, requested that FEMA evaluate the effects that updated topographic and hydrologic data along Ethanac Wash from its confluence with the San Jacinto River to just downstream of the Atchison, Topeka & Santa Fe Railway; an existing bridge at Interstate Highway 395 (I-395); and proposed placement of fill for the development of Tract 29113 along Ethanac Wash from approximately 1,500 feet upstream to approximately 2,600 feet upstream of I-395 would have on the flood hazard information shown on the effective FIRM and FIS report.

All data required to complete our review of this request for a Conditional Letter of Map Revision (CLOMR) were submitted with letters from Mr. Hildebrandt.

We reviewed the submitted data and the data used to prepare the effective FIRM for your community and determined that the proposed project meets the minimum floodplain management criteria of the NFIP. The submitted existing conditions HEC-2 hydraulic computer model, dated November 21, 2000, based on updated topographic and hydrologic information, was used as the base conditions model in our review of the proposed conditions model for this CLOMR request. We believe that, if the proposed project is constructed as shown on the plans entitled "Tract No. 29113 Rough Grading Plan," Sheets 1 through 4, prepared by Lohr & Associates Inc., dated October 19, 1999, and the data listed below are received, a revision to the FIRM would be warranted.

Our review of the existing conditions analysis revealed that the width of the Special Flood Hazard Area (SFHA), the area that would be inundated by the flood having a 1-percent chance of being equaled or exceeded in any given year (base flood), decreased compared to the effective SFHA width from approximately 1,000 feet downstream to approximately 2,600 feet upstream of I-395. The maximum decrease in SFHA width, approximately 1,600 feet, occurred just upstream of I-395. However, these modifications may change as a result of the levee failure analysis requested below.

As a result of the proposed project, the width of the SFHA will decrease compared to the existing conditions SFHA width from approximately 1,500 feet upstream to approximately 2,200 feet upstream of I-395. The maximum decrease in SFHA width, approximately 350 feet, will occur approximately 1,500 feet upstream of I-395.

The proposed project will not affect the existing conditions Base Flood Elevations (BFEs) or regulatory floodway width.

In addition to the changes described above, the zone designation along Ethanac Wash will change from Zone A, an SFHA with no BFEs determined, to Zone AE, an SFHA with BFEs determined, and a regulatory floodway will be added to the FIRM.

Upon completion of the project, your community may submit the data listed below and request that we make a final determination on revising the effective FIRM and FIS report.

- Our review of the submitted data revealed that the embankment of Ethanac Road east of its intersection with I-395 is acting as a levee. Documentation to show that the embankment meets the requirements of Section 65.10 of the NFIP regulations must be submitted before we can make a final determination on revising the FIRM. If the embankment cannot meet these requirements, then a new hydraulic analysis assuming the levee does not exist must be submitted, and the SFHA must be mapped in accordance with the procedures outlined in the publication *Guidelines and Specifications for Study Contractors* (FEMA 37).

- Our review of the submitted data revealed several discrepancies between the calculated floodway topwidths in the existing conditions and proposed conditions HEC-2 models and those shown on the submitted work map. Although these discrepancies did not affect our evaluation of the impact of the Tract 29113 development on the existing conditions flood hazards in your community, they must be resolved before we can revise the effective FIRM.

- Detailed application and certification forms, which were used in processing this request, must be used for requesting final revisions to the maps. Therefore, when the map revision request for the area covered by this letter is submitted, Form 1, entitled "Revision Requester and Community Official Form," must be included. (A copy of this form is enclosed.)

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Hydraulic analyses, for as-built conditions, of the base flood and the regulatory floodway must be submitted with Form 4, and a topographic work map showing the revised floodplain and floodway boundaries must be submitted with Form 5.

- Effective June 1, 2000, FEMA revised the fee schedule for reviewing and processing requests for conditional and final modifications to published flood information and maps. In accordance with this schedule, the current fee for this map revision request is $3,400 and must be received before we can begin processing the request. Please note, however, that the fee schedule is subject to change, and requesters are required to submit the fee in effect at the time of the submittal. Payment of this fee shall be made in the form of a check or money order, made payable in U.S. funds to the National Flood Insurance Program, or by credit card. The payment must be forwarded to the following address:

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- A letter stating that your community will adopt and enforce the modified regulatory floodway, OR, if the State has jurisdiction over either the regulatory floodway or its adoption by your community, a copy of your community's letter to the appropriate State agency notifying it of the modification to the regulatory floodway and a copy of the letter from that agency stating its approval of the modification

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If you have any questions regarding floodplain management regulations for your community or the NFIP in general, please contact the Consultation Coordination Officer (CCO) for your community. Information on the CCO for your community may be obtained by calling the Chief, Community Mitigation Programs Branch, Mitigation Division of FEMA in San Francisco, California, at (415) 923-7184. If you have any questions regarding this CLOMR, please call our Map Assistance Center, toll free, at 1-877-FEMA MAP (1-877-336-2627).

Sincerely,

Max H. Yuan, P.E., Project Engineer
Hazards Study Branch
Mitigation Directorate

For: Matthew B. Miller, P.E., Chief
Hazards Study Branch
Mitigation Directorate

Enclosures

cc: The Honorable Tom Mullen
Chairman, Riverside County Board
of Supervisors

Mr. Habib Motlagh
City Engineer
City of Perris

Mr. Howard L. Dickerson
Senior Civil Engineer
Flood Control and Water Conservation District
Riverside County

Mr. Scott R. Hildebrandt, P.E.
Principal Engineer
Albert A. Webb Associates

PUBLIC HEALTH RESPONSES

Request 79 – Please provide a quantitative risk assessment of the fruit and vegetable ingestion pathway for all appropriate toxic air contaminants emitted from the three sources listed above.

Response 79 – The screening level risk assessment for the project has been revised to include fruit and vegetable ingestion. For this revised analysis, it was assumed that 25% of the residences in the project area have gardens and of these people 20% of the fruits and vegetables they eat come from these gardens. Enclosed, as Public Health Attachment 1 is a copy of the AFC health risk assessment summary table that has been revised to include the impacts from fruit and vegetable ingestion. In addition, enclosed as Public Health Attachment 2 are copies of the revised health risk assessment (HRA) modeling files.

PUBLIC HEALTH ATTACHMENT 1

REVISED HEATH RISK ASSESSMENT SUMMARY TABLES

Table 5.2-5 Health Risk Assessment Results (Revised 2/15/02)

	New Equipment	Significance Threshold
Cancer Risk to Maximally Exposed Individual (w/o TBACT)	~~0.28~~ 0.35 in one million	1 in one million
Cancer Risk to Maximally Exposed Individual (w/ TBACT)	~~0.28~~ 0.35 in one million	10 in one million
Acute Noncancer Hazard Index	0.1275	1
Chronic Noncancer Hazard Index	~~0.048~~ 0.029	1

PUBLIC HEALTH ATTACHMENT 2

REVISED HEATH RISK ASSESSMENT MODELING FILES

California Air Resources Board

And

Office of Environmental Health Hazard Assessment

Health Risk Assessment Program

Version 2.0e

INDIVIDUAL CANCER RISK REPORT

Run Made By

twa

sierra

Project : IEEC

Feb. 14, 2002

Pollutant Database Date : Oct. 31, 2000
Database Reference..... : CAPCOA Risk Assessment Guidelines

DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

ANNUAL AVERAGE EMISSION RATE INFORMATION

File: ANNUAL.E96

Pollutant Name	Emission Rate (g/s)
1,3-BUTADIENE	3.589E-05
ACETALDEHYDE	3.343E-03
ACROLEIN	3.082E-04
AMMONIA	1.293E+00
ARSENIC AND COMPOUNDS (INOR	1.170E-05
BENZENE	2.861E-04
BERYLLIUM	2.507E-06
CADMIUM AND COMPOUNDS	2.507E-06
COPPER AND COMPOUNDS	5.850E-06
ETHYL BENZENE	2.682E-03
FORMALDEHYDE	1.352E-02
LEAD AND COMPOUNDS	1.254E-05
MANGANESE AND COMPOUNDS	8.357E-06
MERCURY AND COMPOUNDS (INOR	4.178E-07
N-HEXANE	2.119E-02
NAPHTHALENE	1.112E-04
NICKEL AND COMPOUNDS	1.671E-05
PAH:BENZ(A)ANTHRACENE	1.848E-06
PAH:BENZO(A)PYRENE	1.392E-05
PAH:BENZO(B)FLUORANTHENE	9.238E-07
PAH:BENZO(K)FLUORANTHENE	8.993E-07
PAH:CHRYSENE	2.060E-06
PAH:DIBENZ(A,H)ANTHRACENE	1.921E-06
PAH:INDENO(1,2,3-C,D)PYRENE	1.921E-06
PROPYLENE (PROPENE)	6.316E-02
PROPYLENE OXIDE	2.420E-03
SELENIUM AND COMPOUNDS	1.755E-05
TOLUENE	1.094E-02
XYLENES	5.386E-03
ZINC COMPOUNDS	6.769E-05

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                    EXPOSURE ROUTE INFORMATION

                         File: EXPOSE.I96

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Deposition Velocity (m/s) .....:  0.020

Fraction of Homegrown Produce .:  0.050

Dilution Factor for Farm/Ranch X/Q (ug/m3)/(g/s) ....:   0.0000
Fraction of Animals' Diet From Grazing ..............:   0.0000
Fraction of Animals' Diet From Impacted Feed ........:   0.0000

Fraction of Animals' Water Impacted by Deposition ...:   0.0000

  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume Changes .......:  0.000E+00


Fraction of Meat in Diet Impacted ..: 0.0000

  Beef ................: 0.0000
  Pork ................: 0.0000
  Lamb/Goat ...........: 0.0000
  Chicken .............: 0.0000

Fraction of Milk in Diet Impacted ..: 0.0000

  Goat Milk Fraction ..: 0.0000

Fraction of Eggs in Diet Impacted ..: 0.0000


Fraction of Impacted Drinking Water : 0.0000

  X/Q at water source ..:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00


Fraction of Fish from Impacted Water: 0.0000

  X/Q at Fish Source ...:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00

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44 YEAR
INDIVIDUAL CANCER RISK BY POLLUTANT AND ROUTE

Pollutant	Air	Soil	Skin	Garden	MMilk	Other
1,3-BUTADIENE	3.84E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
ACETALDEHYDE	5.67E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
ARSENIC AND COM	2.43E-08	3.94E-08	8.33E-10	4.11E-09	0.00E+00	0.00E+00
BENZENE	5.22E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
BERYLLIUM	3.78E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CADMIUM AND COM	6.62E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FORMALDEHYDE	5.10E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LEAD AND COMPOU	9.46E-11	2.39E-10	5.06E-12	2.52E-11	0.00E+00	0.00E+00
NICKEL AND COMP	2.73E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
PAH:BENZ(A)ANTH	1.28E-10	1.97E-10	1.25E-10	4.64E-10	5.04E-10	0.00E+00
PAH:BENZO(A)PYR	9.62E-09	1.48E-08	9.41E-09	3.49E-08	3.79E-08	0.00E+00
PAH:BENZO(B)FLU	6.39E-11	9.83E-11	6.24E-11	2.32E-10	2.52E-10	0.00E+00
PAH:BENZO(K)FLU	6.22E-11	9.57E-11	6.08E-11	2.26E-10	2.45E-10	0.00E+00
PAH:CHRYSENE	1.42E-11	2.19E-11	1.39E-11	5.17E-11	5.61E-11	0.00E+00
PAH:DIBENZ(A,H)	1.45E-09	6.99E-10	4.43E-10	1.65E-09	1.79E-09	0.00E+00
PAH:INDENO(1,2,	1.33E-10	2.04E-10	1.30E-10	4.82E-10	5.24E-10	0.00E+00
PROPYLENE OXIDE	5.63E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Route Total	1.20E-07	5.57E-08	1.11E-08	4.22E-08	4.13E-08	0.00E+00

TOTAL RISK: 2.71E-07

70 YEAR
INDIVIDUAL CANCER RISK BY POLLUTANT AND ROUTE

Pollutant	Air	Soil	Skin	Garden	MMilk	Other
1,3-BUTADIENE	6.10E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
ACETALDEHYDE	9.03E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
ARSENIC AND COM	3.86E-08	4.57E-08	9.67E-10	6.34E-09	0.00E+00	0.00E+00
BENZENE	8.30E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
BERYLLIUM	6.02E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CADMIUM AND COM	1.05E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FORMALDEHYDE	8.11E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
LEAD AND COMPOU	1.50E-10	2.77E-10	5.87E-12	3.88E-11	0.00E+00	0.00E+00
NICKEL AND COMP	4.34E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
PAH:BENZ(A)ANTH	2.03E-10	3.04E-10	1.93E-10	7.38E-10	0.00E+00	0.00E+00
PAH:BENZO(A)PYR	1.53E-08	2.29E-08	1.46E-08	5.56E-08	0.00E+00	0.00E+00
PAH:BENZO(B)FLU	1.02E-10	1.52E-10	9.66E-11	3.69E-10	0.00E+00	0.00E+00
PAH:BENZO(K)FLU	9.89E-11	1.48E-10	9.41E-11	3.59E-10	0.00E+00	0.00E+00
PAH:CHRYSENE	2.27E-11	3.39E-11	2.15E-11	8.22E-11	0.00E+00	0.00E+00
PAH:DIBENZ(A,H)	2.31E-09	1.08E-09	6.86E-10	2.62E-09	0.00E+00	0.00E+00
PAH:INDENO(1,2,	2.11E-10	3.16E-10	2.01E-10	7.67E-10	0.00E+00	0.00E+00
PROPYLENE OXIDE	8.95E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Route Total	1.91E-07	7.09E-08	1.68E-08	6.69E-08	0.00E+00	0.00E+00

TOTAL RISK: 3.46E-07

California Air Resources Board

And

Office of Environmental Health Hazard Assessment

Health Risk Assessment Program

Version 2.0e

CHRONIC NONINHALATION EXPOSURE REPORT

Run Made By

twa

sierra

Project : IEEC

Feb. 14, 2002

Pollutant Database Date : Oct. 31, 2000
Database Reference..... : CAPCOA Risk Assessment Guidelines

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DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

--

ANNUAL AVERAGE EMISSION RATE INFORMATION

File: ANNUAL.E96

Pollutant Name	Emission Rate (g/s)
1,3-BUTADIENE	3.589E-05
ACETALDEHYDE	3.343E-03
ACROLEIN	3.082E-04
AMMONIA	1.293E+00
ARSENIC AND COMPOUNDS (INOR	1.170E-05
BENZENE	2.861E-04
BERYLLIUM	2.507E-06
CADMIUM AND COMPOUNDS	2.507E-06
COPPER AND COMPOUNDS	5.850E-06
ETHYL BENZENE	2.682E-03
FORMALDEHYDE	1.352E-02
LEAD AND COMPOUNDS	1.254E-05
MANGANESE AND COMPOUNDS	8.357E-06
MERCURY AND COMPOUNDS (INOR	4.178E-07
N-HEXANE	2.119E-02
NAPHTHALENE	1.112E-04
NICKEL AND COMPOUNDS	1.671E-05
PAH:BENZ(A)ANTHRACENE	1.848E-06
PAH:BENZO(A)PYRENE	1.392E-05
PAH:BENZO(B)FLUORANTHENE	9.238E-07
PAH:BENZO(K)FLUORANTHENE	8.993E-07
PAH:CHRYSENE	2.060E-06
PAH:DIBENZ(A,H)ANTHRACENE	1.921E-06
PAH:INDENO(1,2,3-C,D)PYRENE	1.921E-06
PROPYLENE (PROPENE)	6.316E-02
PROPYLENE OXIDE	2.420E-03
SELENIUM AND COMPOUNDS	1.755E-05
TOLUENE	1.094E-02
XYLENES	5.386E-03
ZINC COMPOUNDS	6.769E-05

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                    EXPOSURE ROUTE INFORMATION

                         File: EXPOSE.I96

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Deposition Velocity (m/s) .....:  0.020

Fraction of Homegrown Produce .:  0.050

Dilution Factor for Farm/Ranch X/Q (ug/m3)/(g/s) ....:   0.0000
Fraction of Animals' Diet From Grazing ..............:   0.0000
Fraction of Animals' Diet From Impacted Feed ........:   0.0000

Fraction of Animals' Water Impacted by Deposition ...:   0.0000

  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume Changes .......:  0.000E+00


Fraction of Meat in Diet Impacted ..: 0.0000

  Beef ................: 0.0000
  Pork ................: 0.0000
  Lamb/Goat ...........: 0.0000
  Chicken .............: 0.0000

Fraction of Milk in Diet Impacted ..: 0.0000

  Goat Milk Fraction ..: 0.0000

Fraction of Eggs in Diet Impacted ..: 0.0000


Fraction of Impacted Drinking Water : 0.0000

  X/Q at water source ..:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00


Fraction of Fish from Impacted Water: 0.0000

  X/Q at Fish Source ...:     0.0000
  Surface Area (m2) ....:  0.000E+00
  Volume (liters) ......:  0.000E+00
  Volume changes .......:  0.000E+00

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CHRONIC NONINHALATION EXPOSURE

Pollutant	Avg. Dose (mg/kg-d)	REL (mg/kg-d)	Avg Dose/REL
1,3-BUTADIENE	---	---	---
ACETALDEHYDE	---	---	---
ACROLEIN	---	---	---
AMMONIA	---	---	---
ARSENIC AND COMPOUNDS (I	3.53E-08	3.00E-04	1.18E-04
BENZENE	---	---	---
BERYLLIUM	7.51E-09	2.00E-03	3.76E-06
CADMIUM AND COMPOUNDS	9.14E-09	5.00E-04	1.83E-05
COPPER AND COMPOUNDS	---	---	---
ETHYL BENZENE	---	---	---
FORMALDEHYDE	---	---	---
LEAD AND COMPOUNDS	3.79E-08	---	---
MANGANESE AND COMPOUNDS	---	---	---
MERCURY AND COMPOUNDS (I	1.77E-09	3.00E-04	5.89E-06
N-HEXANE	---	---	---
NAPHTHALENE	8.46E-08	---	---
NICKEL AND COMPOUNDS	---	5.00E-02	---
PAH:BENZ(A)ANTHRACENE	1.03E-09	---	---
PAH:BENZO(A)PYRENE	7.76E-09	---	---
PAH:BENZO(B)FLUORANTHENE	5.15E-10	---	---
PAH:BENZO(K)FLUORANTHENE	5.01E-10	---	---
PAH:CHRYSENE	1.15E-09	---	---
PAH:DIBENZ(A,H)ANTHRACEN	1.07E-09	---	---
PAH:INDENO(1,2,3-C,D)PYR	1.07E-09	---	---
PROPYLENE (PROPENE)	---	---	---
PROPYLENE OXIDE	---	---	---
SELENIUM AND COMPOUNDS	---	---	---
TOLUENE	---	---	---
XYLENES	---	---	---
ZINC COMPOUNDS	---	---	---

California Air Resources Board

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--

DILUTION FACTOR FOR POINT UNDER EVALUATION

X/Q (ug/m3)/(g/s) : 1.00E+00

--

ANNUAL AVERAGE EMISSION RATE INFORMATION

File: ANNUAL.E96

Pollutant Name	Emission Rate (g/s)
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ACETALDEHYDE	3.343E-03
ACROLEIN	3.082E-04
AMMONIA	1.293E+00
ARSENIC AND COMPOUNDS (INOR	1.170E-05
BENZENE	2.861E-04
BERYLLIUM	2.507E-06
CADMIUM AND COMPOUNDS	2.507E-06
COPPER AND COMPOUNDS	5.850E-06
ETHYL BENZENE	2.682E-03
FORMALDEHYDE	1.352E-02
LEAD AND COMPOUNDS	1.254E-05
MANGANESE AND COMPOUNDS	8.357E-06
MERCURY AND COMPOUNDS (INOR	4.178E-07
N-HEXANE	2.119E-02
NAPHTHALENE	1.112E-04
NICKEL AND COMPOUNDS	1.671E-05
PAH:BENZ(A)ANTHRACENE	1.848E-06
PAH:BENZO(A)PYRENE	1.392E-05
PAH:BENZO(B)FLUORANTHENE	9.238E-07
PAH:BENZO(K)FLUORANTHENE	8.993E-07
PAH:CHRYSENE	2.060E-06
PAH:DIBENZ(A,H)ANTHRACENE	1.921E-06
PAH:INDENO(1,2,3-C,D)PYRENE	1.921E-06
PROPYLENE (PROPENE)	6.316E-02
PROPYLENE OXIDE	2.420E-03
SELENIUM AND COMPOUNDS	1.755E-05
TOLUENE	1.094E-02
XYLENES	5.386E-03
ZINC COMPOUNDS	6.769E-05

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CHRONIC INHALATION HAZARD INDEX

Pollutant	Resp	CV/BL	CNS	Skin	Repro	Kidn	GI/LV	Immun
1,3-BUTADIENE	--	--	--	--	<.0001	--	--	--
ACETALDEHYDE	0.0004	--	--	--	--	--	--	--
ACROLEIN	0.0051	--	--	0.0051	--	--	--	--
AMMONIA	0.0065	--	--	--	--	--	--	--
ARSENIC AND COM	--	0.0004	0.0004	--	0.0004	--	--	--
BENZENE	--	<.0001	<.0001	--	<.0001	--	--	--
BERYLLIUM	0.0005	--	--	--	--	--	--	--
CADMIUM AND COM	0.0001	--	--	--	--	0.0001	--	--
COPPER AND COMP	<.0001	--	--	--	--	--	--	--
ETHYL BENZENE	--	--	--	--	<.0001	<.0001	<.0001	--
FORMALDEHYDE	0.0045	--	--	0.0045	--	--	--	--
MANGANESE AND C	--	--	<.0001	--	--	--	--	--
MERCURY AND COM	--	--	<.0001	--	--	--	--	--
N-HEXANE	--	--	<.0001	--	--	--	--	--
NAPHTHALENE	<.0001	--	--	--	--	--	--	--
NICKEL AND COMP	0.0003	0.0003	--	--	--	--	--	--
PROPYLENE (PROP	<.0001	--	--	--	--	--	--	--
PROPYLENE OXIDE	<.0001	--	--	--	--	--	--	--
SELENIUM AND CO	<.0001	--	--	--	--	--	--	--
TOLUENE	<.0001	--	<.0001	--	<.0001	--	--	--
XYLENES	<.0001	--	<.0001	--	--	--	--	--
ZINC COMPOUNDS	<.0001	<.0001	--	--	--	--	--	--
Total Chronic	0.0177	0.0007	0.0005	0.0096	0.0004	0.0001	<.0001	--

A Zero Background Concentration file was used to perform this analysis, therefore, there is no contribution from background pollutants.

SOIL AND WATER RESPONSES

Request 89 – Please address the feasibility of dry, hybrid wet-dry, and spray-enhanced dry cooling.

Response 89 – See detailed response in Soil & Water Attachment #1.

Request 129 – Please describe how process drainage sent to the oil/water separator and Holding Tank will be analyzed, before transfer to the cooling tower. Explain how the cooling tower and condensers would deal with significant oil or chemical spills.

Response 129 - There is no "holding tank" associated with the process drainage system. Hazardous materials will be stored in containment areas meeting the requirements of Article 80 of the Uniform Fire Code. Each containment area will be provided with a controlled release whereby stormwater or washdown water can be drained from the area. The controlled release will be via a manually operated normally closed drain valve or a manually operated sump pump. Prior to draining water from a containment area, the operator will verify that the water is suitable for discharge to the process drainage system, thus it is not feasible for significant quantities of oil or chemicals to enter the process drainage system. An in-line oil/water separator will remove minor amounts of oil from the process wastewater prior to discharge to the cooling tower. Minor quantities of chemicals discharged to the process wastewater system will be sufficiently diluted in the cooling tower basin to avoid damage to the cooling tower or condenser.

SOIL & WATER ATTACHMENT 1

DRY COOLING ANALYSIS

Introduction

Although alternative cooling technologies such as dry and wet/dry cooling may be technically feasible, they represent a substantial economic penalty for the Inland Empire Energy Center (IEEC). Prior to discussing alternative cooling technologies, it is important to understand the design basis for the IEEC.

The IEEC will be a "merchant plant" meaning that its financial viability will be contingent upon its ability to compete in the deregulated energy market. The Applicant's project goals include providing a clean, reliable, and highly competitive source of energy for California's electric customers. The IEEC is intended to meet these goals for both the base load generation as well as the peaking capacity.

The thermal cycle proposed for the IEEC is the Applicant's "high power density (HPD)" design. This design includes a substantial amount of duct firing within the heat recovery steam generators (HRSG) to produce additional steam, which, in turn, is converted to electrical energy by the steam turbine generator. Injecting power augmentation steam into the combustion turbines provides additional peak generation. By using this design, the Applicant will be able to provide peaking capacity approximately 10 percent more efficiently than a combustion turbine operating in simple cycle mode. To accomplish this, the IEEC design includes an oversized steam turbine, condenser, and cooling system. The incremental capital cost of these larger components is less than that the cost of a simple cycle combustion turbine to replace this peaking capacity. Thus, this form of peaking capacity is less expensive both in terms of capital cost, as well as operating cost when compared to simple cycle combustion turbines. Another advantage of the IEEC design is that few additional pieces of equipment are required (duct burners, duct burner skid, and a minimal amount of piping) to provide this peaking capacity. By comparison, replacing the IEEC peaking capacity with one or more simple cycle combustion turbines would require the installation of combustion turbines, catalysts for emissions control, exhaust stacks, generator step-up transformers, a larger switchyard, additional land, foundations, piping, and electrical support work.

The Applicant's HPD design results in environmental benefits because by building base load plants with peaking capacity, the need to build other plants, either base load or peaking, is reduced. Therefore, by incorporating significant peaking in base load plants, additional environmental impacts associated with new plants are avoided.

When considering the purpose of the Applicant's HPD design, the addition of "dry" cooling is an unreasonable combination. In comparison to other 2x1 combined cycle plants, the IEEC design provides exceptional peaking with a negligible heat rate increase at base load. The HPD design was developed in response to the pressing need for cost-effective and efficient peaking capacity in locations such as California. On a hot design day, the IEEC as presently designed would be capable of a peak output of 670 MW through the use of HRSG duct firing and combustion turbine power augmentation steam injection. "Dry" cooling reduces that peak output to 649 MW, a 21 MW decrease. The "dry" cooling design compared to "wet" cooling design is also about $27.5 million more expensive in capital cost. The combination of the Applicant's HPD design and "dry" cooling is technically feasible, but not economically sensible.

If "wet" cooling were not used, the Applicant would need to re-optimize the design, incorporating peaking capacity economically compatible with "dry" cooling. Such changes would constitute a major change to the project description requiring re-analysis of many areas of the AFC. Also, substantial changes to the project configuration and output might result in the loss of interconnection queue position with Southern California Edison (SCE), thus potentially burdening the project with additional transmission congestion mitigation costs and requiring a new System Impact Study.

Alternative Cooling Technologies

Technically feasible alternatives to the proposed "wet" cooling system include "dry" cooling and "wet/dry" cooling. The following is a brief analysis of these alternatives.

"Dry" Cooling

With the Applicant's proposed "wet" cooling system, steam exiting the steam turbine is condensed in a shell and tube heat exchanger, or surface condenser. Circulating water flowing through the tube side of the heat exchanger is used to cool and condense the steam. The circulating water is passed through a mechanical-draft cooling tower where the heat is removed. The primary mechanism by which waste heat is discharged to the atmosphere is through latent heat transfer, or evaporation, whereby the temperature of the air leaving the cooling tower is raised only slightly but the humidity is significantly increased. The majority of the water consumed by a "wet" cooled plant is to replace the circulating water lost to evaporation.

With the "dry" cooling alternative, an air-cooled condenser would replace the surface condenser and cooling tower. An air-cooled condenser contains finned tubes through which the steam flows. Large fans blow ambient air across the finned tubes to condense the steam. The mechanism used to reject waste heat to the atmosphere with the "dry" cooling alternative is sensible heat transfer, whereby the temperature of the air leaving the air-cooled condenser is significantly increased. However, with this process, no water is required to condense steam.

Economic Impacts

Capital Cost

A comparison of the incremental capital costs of the "dry" cooled alternative versus the proposed "wet" cooled project was made for the IEEC. The "dry" cooled alternative is conservatively estimated to cost $27.5 million (2001 dollars) more than the proposed "wet" cooled system (see Tables 1 and 2). Assuming an inflation rate of 2.5 percent per year, this difference amounts to $29.6 million when built. The cost comparison includes not only the equipment described above for the two systems but also the plant linear facilities and auxiliary systems that would be sized much smaller for the "dry" system than for the "wet" system. These include changes to the raw and recycled water delivery systems, recycled water storage tank, and non-reclaimable wastewater pipeline. The capital costs associated with the wet cooling design are delineated in Table 1 and the capital costs associated with dry cooling are shown in Table 2.

Operating Cost

A comparison was also made of the estimated operating costs for the "dry" cooled alternative versus those for the proposed "wet" cooled project. With the "dry" cooled alternative, there would be reductions in recycled water, water treatment chemical, and wastewater disposal costs. These savings are estimated to total $1.34 million per year (2001 dollars) or $1.44 million in 2005 assuming an inflation rate of 2.5 percent per year (see Tables 3 and 4).

Plant Efficiency and Output

"Dry" cooling negatively impacts plant efficiency in two areas; 1) decreased steam turbine output, and 2) increased parasitic losses (or auxiliary loads). With the proposed "wet" cooled project, within the surface condenser, the steam is cooled to within about 31 degrees Fahrenheit (F) of the incoming circulating water temperature, on a hot day at peak load. The cooling tower, in turn, is designed to cool the circulating water to within 8 degrees F of the ambient wet bulb temperature. For instance, assuming a design ambient wet bulb temperature of 72 degrees F, the resulting steam temperature will be about 111 degrees F, corresponding to a steam turbine exhaust pressure of about 2.7 inches of mercury (absolute). With a "dry" cooling system, a reasonable design criterion for an air-cooled condenser is to size the condenser for an initial temperature difference (ITD) of about 45 degrees F. The ITD is the difference between the steam temperature and the ambient dry bulb temperature. Assuming a design dry bulb temperature of 97 degrees F, the resulting steam temperature would be 142 degrees F, corresponding to a steam turbine exhaust pressure of about 6.2 inches of mercury, which is dangerously close to the expected steam turbine trip pressure of 6.5 inches of mercury. For the IEEC, because of the high ambient temperatures, it would be necessary to design the air-cooled condenser for a lower ITD. Assuming a design dry bulb temperature of 97 degrees F and an ITD of 33 degrees F, the resulting steam temperature would be 130 degrees F, corresponding to a steam turbine exhaust pressure of about 4.5 inches of mercury. The loss of steam turbine output resulting from an increase in exhaust pressure from 2.7 inches to 4.5 inches presents a significant operational impact. Table 5 indicates the estimated reduction in steam turbine output that would result at the IEEC for a variety of operating conditions in the event that the "dry" cooling alternative was used. Because air-cooled condensers reject 100 percent of the heat by means of sensible heat transfer, the "dry" cooling alternative needs to move much more air than the proposed "wet" system, which rejects most of its heat using latent heat transfer (i.e. evaporation). For the IEEC, the cooling tower proposed for the "wet" cooled system has 14 cells, each with a 150 horsepower (hp) fan, drawing a total load of about 2,900 brake-horsepower (bhp). For the "dry" cooled option, the air-cooled condenser is estimated to have 70 cells, each with a 200 hp motor, drawing a total load of about 8,700 bhp. Table 5 indicates the loss in net plant output for the "dry" cooled alternative as compared to the proposed "wet" cooled plant for several operating conditions.

TABLE 1
Capital Cost for Proposed "Wet" Cooled Facilities

Description	Capital Cost
Cooling Tower (includes erection)	$ 5,910,000
Cooling Tower Basin	1,570,000
Circulating Water Pumps	960,000
Circulating Water Piping	2,140,000
Circulating Water Chemical Systems	200,000
Surface Condenser	5,410,000
Auxiliary Heat Exchangers (shell & tube)	400,000
Auxiliary Cooling Water Pump	130,000
Water/Wastewater Treatment	2,430,000
Recycled Water Storage Tank	1,250,000
Non-Reclaimable Wastewater Storage Tank	120,000
Raw & Recycled Water Pump Stations	1,490,000
Non-Reclaimable Wastewater Pipeline	2,380,000
Motor Control Centers	250,000
Electrical	780,000
Instrumentation and Control	160,000
Site/Civil	430,000
Total Direct Costs	$ 26,010,000
Construction Management (2%)	520,000
Engineering (2%)	520,000
Indirect Cost (5%)	1,300,000
Contingency & Fee (10%)	2,600,000
Non-Reclaimable Wastewater Pipeline Capacity Charge	10,340,000
Total Capital Cost	$ 41,290,000

TABLE 2
Capital Cost for Alternative "Dry" Cooled Facilities

Description	Capital Cost
Air-Cooled Condenser (excludes erection)	$ 32,500,000
Condenser Foundations	700,000
Condenser Erection	10,080,000
Steam Turbine Exhaust Duct	1,080,000
Hotwell/Condensate Tank, etc.	180,000
Condenser Wash System	260,000
Auxiliary Heat Exchangers (fin-fan)	1,200,000
Water/Wastewater Treatment	2,300,000
Recycled Water Storage Tank	100,000
Non-Reclaimable Wastewater Storage Tank	20,000
Non-Reclaimable Wastewater Pipeline	1,190,000
Motor Control Centers	3,500,000
Electrical	2,500,000
Instrumentation and Control	500,000
Site/Civil	1,100,000
Total Direct Costs	$ 57,210,000
Construction Management (2%)	1,140,000
Engineering (2%)	1,140,000
Indirect Cost (5%)	2,860,000
Contingency & Fee (10%)	5,720,000
Non-Reclaimable Wastewater Pipeline Capacity Charge	750,000
Total Capital Cost	$ 68,820,000

TABLE 3
Annual Operating Cost for Proposed "Wet" Cooled Facilities

Description	Annual Cost
Water	$ 620,000
Cooling Tower Chemicals	540,000
Non-Reclaimable Wastewater Disposal	210,000
Total Annual Operating Cost	$ 1,370,000

TABLE 4
Annual Operating Cost for Alternative "Dry" Cooled Facilities

Description	Annual Cost
Water	$ 20,000
Non-Reclaimable Wastewater Disposal	10,000
Total Annual Operating Cost	$ 30,000

TABLE 5
Decrease in Plant Output for "Dry" Cooling Compared to "Wet" Cooling

Operating Condition	Net Loss in Power Generation
Hot Day (97 °F Dry Bulb, 72 °F Wet Bulb) with full peaking (power augmentation and duct firing)	20.7 MW
Hot Day (97 °F Dry Bulb, 72 °F Wet Bulb) at base load (no power augmentation or duct firing)	16.1 MW
Average Temperature Day (61 °F Dry Bulb, 54 °F Wet Bulb) with full peaking (power augmentation and duct firing	9.0 MW
Average Temperature Day (61 °F Dry Bulb, 54 °F Wet Bulb) at base load (no power augmentation or duct firing)	3.9 MW

As can be seen from the Table 5, the loss in plant output resulting from "dry" cooling is greatest at the highest ambient temperature, about twice the loss at the average ambient temperature. Unfortunately, because California is a summertime peak market, the greatest loss in output would coincide with the time of year when electrical demand is greatest. "Dry" cooling would thus be more suitable for markets having peak demands that occur in the winter or in areas with more moderate weather.

The first operating year revenue loss from lost electricity revenue is estimated at $6.22 million. Because the IEEC HPD design was chosen to provide peaking capacity for California's peak periods (principally the summer daytime hours) and because dry cooling has the most detrimental effect on output during California's peak period, the economic penalty of dry cooling is evaluated based on a lost electricity revenue calculation appropriate for peaking power rather than baseload generation. The peak electricity value was based upon daily data published by Megawatt Daily for peak power in electricity market SP-15 for 1999, 2000, and 2001. (Peak power is defined as 16 hours per day, Monday to Saturday.) Only the prices for the top 3,000 hours in each year were used and averaged for an average peak price for the 1999 to 2001 period; this average was then escalated for 4 years at 2.5 percent for a 2005 peak price of approximately $0.142/kWh. An analysis of temperature data representative of the site indicated the top 3,000 hours of the year have an average temperature of 78.3 degrees F, and a linear interpolation between the 97 and 61 degree F cases with full peaking from Table 5 indicates a net power loss of 14.6 MW at this temperature. The 2005 revenue loss is the product of the average output loss of 14.6 MW x 3,000 hours x $0.142/kWh, or $6.22 million.

This analysis understates the lost electricity revenues for several reasons. The price data averages the daily price over a 16-hour period, which includes some hours where energy prices would not be expected to be particularly high. The calculation of lost energy production also somewhat understates the lost revenues, since dry cooling still reduces output even when temperatures are below the top 3,000 hours and power augmentation and duct firing are not occurring, but it captures most of the loss. (Note that there is no off-setting decrease in fuel costs since the same amount of fuel is being used with both the dry-cooling and wet-cooling design.)

Total Costs Due to Dry Cooling

The planned life of the generating facility is 30 years. Therefore the total costs of dry cooling are the sum of the increase in capital cost ($29.6 million) and the yearly difference between lost revenues and operating cost savings for 30 years. In 2005 the difference is $4.8 million ($6.22 million - $1.44 million), and it is assumed to increase at 2.5 percent per year, an estimate of the rate of inflation. The cumulative 30-year loss is $209.9 million, plus an increase in capital costs of $29.6 million for a total cost to the project for dry cooling of $240 million, a very substantial sum.

Environmental Impacts

Land Use

The cooling tower used for the proposed wet cooling design occupies approximately 1.8 acres. When the access area surrounding the cooling tower and the cooling tower chemical/electrical building are included, the total occupied area increases to about 3.2 acres. The air-cooled condenser used for the alternative dry cooling design would occupy approximately 2.4 acres. Including the access area surrounding the air-cooled condenser and the steam exhaust duct, the total occupied area increases to about 3.7 acres. Thus, the amounts of land occupied by the two cooling systems are comparable.

Noise

The far field noise levels from air-cooled condensers are generally greater than those for cooling towers. This is mainly a result of the number of fans and height at which the fans, gearboxes, and motors are located (approximately 90 feet above grade), meaning there is almost no blockage from other plant equipment. Air-cooled condensers can be made much quieter by using special low-noise fans. Nonetheless, providing significant reduction in air-cooled condenser noise emissions quickly becomes cost-prohibitive. Other than using low noise or ultra low noise fans, the only way to significantly reduce noise is to reduce the speed of the fans. As the fan speed is decreased, the air flow rate also decreases requiring more heat transfer surface area to condense the same amount of steam. For the purpose of this analysis, an oversized air-cooled condenser has been assumed in order to provide an overall plant noise level equivalent to that of the proposed cooling tower.

Visibility

At times when temperatures are low and humidity is high, cooling towers can create visible water vapor plumes. Given the project area's climatic conditions, with a "wet" design, cooling tower plumes would be most likely to form during the winter months, particularly at night and in the early morning hours. Because the plumes are most likely to be present at night, and at times when fog or rain is present, the number of hours that plumes would be readily visible would be limited to some degree. The extent to which the plumes would be considered to create visual impacts would depend upon plume size and duration, viewer sensitivity, the distance of the plume from the viewers and the visual context.

An advantage of the "dry" cooled design is that it does not produce a visible water vapor plume, thus eliminating any plume-related visual effects that might be associated with a "wet" design. The visual price paid for elimination of the plumes is the presence of a piece of project equipment, the air-cooled condenser, that is much taller, bulkier, and visually salient than the cooling tower it replaces. The cooling tower proposed for the IEEC is approximately 840 feet long, 66 feet wide, and 59 feet tall. The air-cooled condenser would be about 540 feet long, 195 feet wide, and 130 feet tall, over twice as high as the cooling tower.

Review of photographs of the recently built Sutter Energy Center provides a sense of the implications that an air-cooled condenser has for a combined cycle power plant. In reviewing these photographs, it is important to keep in mind that the air-cooled condenser at the Sutter project is substantially smaller than the one that would be required at IEEC (6 bays at Sutter vs. 14 at IEEC) and is not as tall (the Sutter condenser is only 87 feet tall while the one at IEEC would be about 130 feet tall). Figure 1 is a view of the power plant from a distance of about 0.75 mile from the site. In this view, the air-cooled condenser is the large rectangular box structure elevated on a steel support framework. At Sutter, the air-cooled condenser is as tall as the HRSG units and visually appears to be nearly as tall as the HRSG stacks. Because of its bulk and its elevated position, the air-cooled condenser is the most visually prominent element of the power plant facility, and it blocks views of the background and contrasts with its backdrop to a much greater extent than the HRSG units. Figure 2 is a view of the Sutter Energy Center from a viewpoint approximately 1.75 miles away. This view illustrates that at this distance many of the plant's elements appear to be close to the horizon line and integrate into the overall landscape pattern. In contrast, the air-cooled condenser is seen as an element that attracts attention to itself because it rises above the horizon where it is highly visible, and has a scale and form that is substantially different from that of the landscape's other elements.

Based on the experience at the Sutter Energy Center, it can be seen that the air-cooled condenser at IEEC is likely to increase the overall visibility of the IEEC, the extent to which views of background features might be blocked, and the degree to which the facility will contrast with its landscape setting. Although the air-cooled condenser would eliminate the visual effects of water vapor plumes that would be visible for a limited number of hours during the course of the year, it would create structural impacts that would be a permanent feature of the landscape.

The potential for increased HRSG exhaust stack heights (as discussed in the Air Quality section below) from a "dry" cooled project has the potential to create a further increase in project visual impacts.

Air Quality

There are no emissions associated with the "dry" cooling alternative. With the proposed "wet" cooled plant, the PM10 particulate emissions associated with the dissolved solids in the cooling tower drift have been conservatively estimated at 14.5 tons per year. This amount represents about 10 percent of the total particulate emissions projected for the IEEC. These emissions would be eliminated with "dry" cooling.

Because of its size, the air-cooled condenser may present significant downwash issues. The condenser height of approximately 130 feet results in a structure that would most likely influence the dispersion of plumes from the HRSGs, auxiliary boiler, and emergency equipment. It would be possible to increase the stack heights to compensate for this impact, however, an increase in the height of the HRSG exhaust stacks will cause the stacks to be considered an aviation obstruction by the FAA, requiring the Applicant to install and operate lighting markers. These markers would further impact the visual impact of a "dry" cooled project on this site.

Water Resources

The projected average annual water usage for the IEEC is about 4,150 acre-feet per year (AFY). The use of "dry" cooling at the IEEC would reduce water consumption by about 97 percent to about 120 AFY. The water use associated with the "dry" cooling alternative is for boiler makeup (to replenish losses resulting from blowdown and power augmentation), combustion turbine inlet air fogging, and potable and service water needs. While the water consumption for the IEEC would be reduced significantly using a "dry" cooling system, this would also reduce or eliminate many of the benefits associated with using recycled water at the IEEC. Included in these benefits are the following:

- Improved recycled water revenues enabling continued viability of EMWD water management programs
- Significant recycled water demands during winter months, which help to maximize recycled water use within EMWD's service territory
- A reduction in incidental groundwater recharge thereby reducing degradation of groundwater and migration of high-saline water into low TDS groundwater basins
- A net export of salt from the region via cooling tower blowdown discharged to the non-reclaimable wastewater system

Wastewater Discharge

As the IEEC is proposed to discharge process wastewater to EMWD's non-reclaimable wastewater system, a system designed specifically to accept wastewater streams high in total dissolved solids (TDS), there would be no direct impact associated with either the proposed "wet" cooled project or the "dry" cooled alternative. Since the "wet" cooled project would result in a greater discharge to the non-reclaimable wastewater system, EMWD would receive greater revenues from the discharge, helping to offset their capital investment in this system.

Use of Resources

The proposed "wet" cooling system would use large quantities of recycled water. During the initial years of the project, in the event that EMWD does not have sufficient recycled water available to meet the IEEC demand, it may be necessary for EMWD to supplement their recycled water system with raw water from the Colorado River Aqueduct. Both the recycled water and the raw (untreated) surface water are considered renewable resources. Through the high fuel efficiency of the proposed combined-cycle design, the IEEC will provide a greater beneficial use of this water than most other water-cooled power plants. Although the "dry" cooled alternative will significantly reduce the amount of water consumed, the loss in plant electrical output would result in a less-efficient use of natural gas, a non-renewable resource.

"Wet/Dry" Cooling

The "wet/dry" cooling alternative is a hybrid of the "wet" and "dry" systems previously described. This alternative includes a cooling tower/surface condenser system operated in parallel with an air-cooled condenser. The concept behind this system is that during cooler weather, the air-cooled condenser could perform the majority of the cooling thus conserving water. During hot weather, the cooling tower could perform the majority of the cooling, thus achieving a lower steam turbine exhaust pressure and therefore a greater plant output than would have been achievable using an air-cooled condenser alone. The "wet/dry" cooling system is most appropriate for plants where there is sufficient water available during hot weather, but where there is a limited supply on an overall annual use basis (e.g. a limited groundwater resource). Since the IEEC proposes to use recycled water that would be available in greater quantities during cool weather seasons than it would during hot weather when irrigation demands are greater, this alternative was not considered further for the IEEC.

"Spray-Enhanced" Dry Cooling

Spray-enhanced dry cooling is understood to mean a system utilizing an air-cooled condenser wherein water is sprayed into the condenser inlet air stream during hot weather to provide some amount of latent cooling, thus achieving a lower steam turbine backpressure. While owners of existing air-cooled condensers may be experimenting with spray-enhanced dry cooling, the Applicant is not aware of any major air-cooled condenser manufacturers offering such a system or guaranteeing its performance. The Applicant considers this type of system experimental in nature and is not prepared to risk its application on the IEEC.

Previous Evaluations

A significant number of analyses have been conducted on the use of "dry" and "wet/dry" cooling alternatives for power plants similar to the IEEC. Previous studies have concluded that the life cycle cost for "dry" cooling is at least two times greater than "wet" cooling. The primary reason for the additional cost is the much higher capital cost for the air-cooled condenser. The construction cost alone for an air-cooled condenser is almost six times that of a cooling tower. For wet/dry cooling, previous studies have shown that the life cycle costs are less dramatic but still quite significant, i.e., at least 50 percent greater.

A capital cost comparison was recently conducted for the proposed 560 MW Rio Linda/Elverta Power Project. This comparison showed that the installed cost for dry cooling was 2.3 times the cost for wet cooling. For wet/dry cooling, the installed cost was 1.8 times greater than wet cooling.

Operating costs for "dry" and "wet/dry" cooling systems are significantly higher due to decreased efficiencies and higher parasitic loads. These operating inefficiencies are greatest in the summer when the demand for efficient plant operation (and the subsequent loss of revenue) is the greatest.

A life cycle cost evaluation of dry and wet/dry cooling alternatives was conducted in 1998 for a similar project, the 700 MW High Desert Power Project (HDPP). The HDPP's conclusions were that the capital cost to use dry or wet/dry cooling was 100 percent and 50 percent higher than wet cooling, respectively. The life cycle costs to use dry cooling were over 5.1 times higher than wet cooling and 3.9 times higher for wet/dry cooling.

Conclusion

Although dry cooling is technically feasible for IEEC, it is undesirable both economically and visually. Notably it also defeats the high power density design (which holds promise for reducing the number of new energy facilities needed in California) by decreasing power output most at those times when California most needs power, hot summer days. Although air-cooled condensers can be similar in land consumption and noise emissions to evaporative cooling towers, their larger, bulkier profile is a permanent visual impact that may not integrate well into the overall landscape pattern. The likely need for higher stacks requiring safety lighting would also increase visual impacts.

Figure 1

Sutter Energy Center - viewed 0.75 miles from site